State of Utah

GARY R. HERBERT
*Governor*

GREG BELL
*Lieutenant Governor*

Department of
Environmental Quality

Amanda Smith
*Executive Director*

DIVISION OF AIR QUALITY
Cheryl Heying
*Director*

DAQE-AN0101230031-10

January 12, 2010

Mike Astin
Holly Refining & Marketing Company
393 S 800 W
Woods Cross, UT 840871435

Dear Mr. Astin:

Re: Approval Order: Modifications to DAQE-AN0101230027-09 to Add Two Boilers
Davis County; CDS A; MACT (Part 63), Major HAP source, NESHAP (Part 61), NSPS (Part 60), NSR, Nonattainment or Maintenance Area, $PM_{10}$ SIP / Maint Plan, PSD, Title V (Part 70) Major source
Project Number: N0101230031

The attached document is the Approval Order for the above-referenced project. Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. The project engineer for this action is Camron Harry, who may be reached at (801) 536-4232.

Sincerely,

M. Cheryl Heying, Executive Secretary
Utah Air Quality Board

MCH:CAH:dn

cc: Mike Owens
Davis County Health Department

# STATE OF UTAH

## Department of Environmental Quality

## Division of Air Quality

# APPROVAL ORDER: Modifications to DAQE-AN0101230027-09 to Add Two Boilers

**Prepared By: Camron Harry, Engineer**
**Phone: (801) 536-4232**
**Email: caharry@utah.gov**

**APPROVAL ORDER NUMBER**

**DAQE-AN0101230031-10**

**Date: January 12, 2010**

**Holly Refining & Marketing Company**
**Woods Cross Refinery**
**Source Contact:**
**Mr. Bo Bothwell**
**Phone: (801) 299-6619**

**M. Cheryl Heying**
**Executive Secretary**
**Utah Air Quality Board**

# Abstract

Holly Refining & Marketing Company (Holly) Woods Cross Refinery is requesting to install two (2) new 75,000 pounds of steam/hour steam boilers, Boiler #9 and Boiler #10. Holly is in the process of installing and operating new sulfur removal units for on and off road fuels in order to comply with federal regulations. These sulfur removal units have been built and as a result the refinery's steam demand has increased. While the possibility of debottlenecking exists with the increased steam capacity, the source wide emissions are capped by the Utah $PM_{10}$ SIP. One of the additional boilers is needed to meet current steam requirements and the second boiler is needed to provide redundancy when a boiler is shut down for maintenance or during a process upset.

This modification will result, in tons per year, in the following PTE increases: $PM_{10}$ +7.82, $NO_x$ +15.65, $SO_2$ +20.69, CO + 28.94. While this is an increase over the values from Holly's existing AO, the new totals are less than the existing limitations from section IX.H.2.f of the $PM_{10}$ SIP.

Holly is located in West Bountiful, Davis County. Davis County is a maintenance area for ozone. Holly is located 4 miles north of Salt Lake County and is defined as a contributing source for the Salt Lake County $PM_{10}$ nonattainment area. While this source is located in an area currently designated as nonattainment for PM2.5, the preparation of this document was completed prior to the effective date of that designation.

The project has been evaluated and found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). A public comment period was held in accordance with UAC R307-401-7 and no comments were received.

This air quality AO authorizes the project with the following conditions, and failure to comply with any of the conditions may constitute a violation of this approval order. This AO is issued to, and applies to the following:


| **Name of Permittee:** | **Permitted Location:** |
|---|---|
| Holly Refining & Marketing Company<br>393 S 800 W<br>Woods Cross, UT 840871435 | Woods Cross Refinery<br>393 South 800 West<br>Woods Cross, UT 84087-1435 |

**UTM coordinates:** 424,000 m Easting, 4,526,277 m Northing
**SIC code:** 2911 (Petroleum Refining)

## Section I: GENERAL PROVISIONS

I.1 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]

I.2 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.3 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]

I.4 All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five (5) years. [R307-401]

I.5 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]

I.6 The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring. [R307-150]

I.7 The owner/operator shall comply with UAC R307-107. General Requirements: Unavoidable Breakdowns. [R307-107]

I.8 Holly Refining and Marketing shall continue to install the vacuum tower, associated heaters, upgrade the FCCU and solvent deasphalting unit, make the required changes in storage tanks, install boilers #9 and #10, and operate its facility in accordance with the terms and conditions of this AO that were written pursuant to Holly's notice of intent submitted to the Division of Air Quality on October 5, 2006.

Holly shall notify the Executive Secretary in writing when the installation of the equipment has been completed and the equipment is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation have not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-18. [R307-401]

## Section II: SPECIAL PROVISIONS

**II.A The approved installations shall consist of the following equipment:**

II.A.1 **Holly Refinery**
Permitted Source

| | |
|---|---|
| II.A.2 | **(4-1) 4H1: FCC feed heater**<br>68.4 MMBtu/hr process furnace, fired on plant gas, restricted to 39.9 MMBtu/hr, equipped with low-$NO_x$ burners |
| II.A.3 | **(4-4a) 4K1A: KVG compressor west**<br>660 hp internal combustion engine, fired on natural gas |
| II.A.4 | **(4-4b) 4K1B: KVG compressor east**<br>660 hp internal combustion engine, fired on natural gas |
| II.A.5 | **(6-1) 6H1: Reformer charge and reheater furnace**<br>54.7 MMBtu/hr process furnace, fired on plant gas |
| II.A.6 | **(6-2) 6H3: Reformer reheat furnace**<br>37.7 MMBtu/hr process furnace, fired on plant gas |
| II.A.7 | **(6-3) 6H2: Prefractionator reboiler heater**<br>12.0 MMBtu/hr process furnace, fired on plant gas |
| II.A.8 | **(6-4a) 6K1 SVG compressor east**<br>325 hp internal combustion engine, fired on natural gas |
| II.A.9 | **(6-4b) 6K2: SVG compressor west**<br>325 hp internal combustion engine, fired on natural gas |
| II.A.10 | **(7-1) 7H3: HF alkylation depropanizer reboiler**<br>33.3 MMBtu/hr process furnace, fired on plant gas |
| II.A.11 | **(7-2) 7H1: HF alkylation regeneration furnace**<br>4.4 MMBtu/hr process furnace, fired on plant gas |
| II.A.12 | **(8-1) 8H1: Crude furnace**<br>99.0 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB |
| II.A.13 | **(9-1) 9H1: DHT reactor charge heater**<br>8.1 MMBtu/hr process furnace, fired on plant gas |
| II.A.14 | **(9-2) 9H2: DHT stripper reboiler**<br>4.1 MMBtu/hr process furnace, fired on plant gas |
| II.A.15 | **(10-2) 10H1: Asphalt mix heater**<br>13.2 MMBtu/hr process furnace, fired on plant gas |
| II.A.16 | **(11-1) 11H1: SRGP depentanizer reboiler**<br>24.2 MMBtu/hr process furnace, fired on plant gas |
| II.A.17 | **(11-2) 11K1: Clark compressor**<br>600 hp internal combustion engine, fired on natural gas |
| II.A.18 | **(12-1) 12H1: NHDS reactor charge furnace**<br>50.2 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB |

II.A.19 **(13-1) 13H1: Isomerization reactor feed furnace**
6.5 MMBtu/hr process furnace, fired on plant gas

II.A.20 **(17-1) SRU - tailgas incinerator**
For SRU under 20 LTPD

II.A.21 **(19-1) DHT reactor charge heater**
18.1 MMBtu/hr Processs Furnace, fired on plant gas, equipped with low-$NO_x$ burners

II.A.22 **20H1: Reactor charge heater**
14.9 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB

II.A.23 **20H2: Fractionator charge heater**
47.1 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB

II.A.24 **(45-1) 45H1: Asphalt mix and storage furnace**
15.3 MMBtu/hr process furnace, fired on plant gas, equipped with low-$NO_x$ burners

II.A.25 **(68-2) 68H2: North in-tank asphalt heater**
0.8 MMBtu/hr tank heater, fired with natural gas

II.A.26 **(68-3) 68H3: South in-tank asphalt heater**
0.8 MMBtu/hr tank heater, fired with natural gas

II.A.27 **(51-4) Boiler #4**
35.6 MMBtu/hr boiler, fired on plant gas

II.A.28 **(51-5) Boiler #5**
70.0 MMBtu/hr boiler, fired on plant gas

II.A.29 **(51-6) CO boiler/FCC scrubber**
60.0 MMBtu/hr boiler, fired on plant gas

II.A.30 **(51-7) FCC 34" CO boiler bypass**
34" Stack

II.A.31 **(51-8) Boiler #8**
92.7 MMBtu/hr boiler, fired on plant gas, equipped with low-$NO_x$ burner

II.A.32 **(51-9) Boiler #9**
89.3 MMBtu/hr boiler, fired on plant gas using SCR

II.A.33 **(51-10) Boiler #10**
89.3 MMBtu/hr boiler, fired on plant gas using SCR

II.A.34 **(56) Watewater Treatment Plant**

II.A.35 **(66-1) Process flare south**
Flare

II.A.36 **(66-2) Process flare north**
Flare

II.A.37 **(68-1) Propane pit flare**
Flare

II.A.38 **Tank 23: Storage vessel - petroleum liquids**
14,600 Bbl capacity storage tank with a fixed roof

II.A.39 **Tank 35: Storage vessel - petroleum liquids**
105,000 Bbl capacity storage tank with a fixed roof

II.A.40 **Tank 71: Storage vessel - petroleum liquids**
67,155 Bbl capacity storage tank with internal floating roof, primary and secondary seals

II.A.41 **Tank 72: Storage vessel - petroleum liquids**
124,388 bbl storage vessel with floating roof, primary and secondary seals

II.A.42 **Tank 79**
10,000 Bbl capacity storage tank with a fixed roof

II.A.43 **Tank 167**
1,300,000 gallon sour water storage tank

II.A.44 **Tank 323: Storage vessel - petroleum liquids**
14,686 bbl capacity storage tank with internal floating roof, and primary seal

II.A.45 **Storage tanks**
Three 14,000 Bbl NaSH tanks (two currently installed)
Two 7,100 Bbl caustic tanks (one currently installed)
One 80,000 Bbl fuel oil tank (not yet installed)
One 50,000 Bbl cutter tank (not yet installed)

II.A.46 **Emergency equipment**
1. Diesel powered water well No. 3
2. Caterpillar diesel fire pump No. 1
3. Caterpillar diesel fire pump No. 2
4. Detroit Diesel fire pump
5. Diesel powered plant air backup compressors (3)
6. Diesel powered standby generator, Boiler House
7. Diesel powered standby generator, Central Control Room

II.A.47 **Three amine units**
Two new units

II.A.48 **Fluid catalytic cracking unit**
FCC includes 02 skid, item #4-97-0010

II.A.49 **DHT**
Distillate hydro-desulfurization treatment unit

II.A.50 **Cooling tower #7**

II.A.51 **Gas oil hydrocracking unit**
Includes reactor charge heater and fractionator charge heater

II.A.52 **Vacuum tower and vacuum furnace heater**
15.2 MMBtu/hr using ultra low-$NO_x$ burners

II.A.53 **Hot oil heater**
99 MMBtu/hr using ultra low-$NO_x$ burners

II.A.54 **Asphalt tank heaters**
two new in-tank heaters sized at 0.8 MMBtu/hr each

II.A.55 **SRU/TGI (2)**
Two new Claus sulfur recovery units with tail gas recovery, each sized at 50 long tons of sulfur per day

II.A.56 **Sour water strippers (2)**
One existing unit (#18), and one new unit (#22) with ammonia stripper

II.A.57 **NaSH sour gas treatment unit**
Sized at 50 long tons of sulfur per day

II.A.58 **Hydrogen plant**
Two hydrogen reformer feed furnaces, each sized at 123.1 MMBtu/hr using ultra low-$NO_x$ burners

II.A.59 **Crude heater**
35 MMBtu/hr using ultra low-$NO_x$ burners

II.A.60 **ETF portable diesel generator**
135 kW diesel-fired generator

II.A.61 **$SO_2$ Emissions Cap Sources**
$SO_2$ Emissions Cap Sources: includes (4-4b) 4K1B: KVG compressor east, (8-1) 8H1: Crude furnace, (10-2) 10H1: Asphalt mix heater, 20H2: Fractionator charge heater, ETF portable diesel generator, (4-4a) 4K1A: KVG compressor west, (51-8) Boiler #8, Hydrogen plant, (6-1) 6H1: Reformer charge and reheater furnace, (7-2) 7H1: HF alkylation regeneration furnace, (51-4) Boiler #4, (68-2) 68H2: North in-tank asphalt heater, (51-9) Boiler #9, (6-4a) 6K1 SVG compressor east, (7-1) 7H3: HF alkylation depropanizer reboiler, (9-1) 9H1: DHT reactor charge heater, 20H1: Reactor charge heater, (6-2) 6H3: Reformer reheat furnace, (45-1) 45H1: Asphalt mix and storage furnace, (19-1) DHT reactor charge heater, (4-1) 4H1: FCC feed heater, (6-3) 6H2: Prefractionator reboiler heater, (13-1) 13H1: Isomerization reactor feed furnace, Vacuum tower and vacuum furnace heater, Asphalt tank heaters, (12-1) 12H1: NHDS reactor charge furnace, (51-5) Boiler #5, Hot oil heater, (9-2) 9H2: DHT stripper reboiler, (11-1) 11H1: SRGP depentanizer reboiler, (68-3) 68H3: South in-tank asphalt heater, (6-4b) 6K2: SVG compressor west, (51-10) Boiler #10

II.A.62 **$NO_x$ Emissions Cap Sources**
$NO_x$ Emissions Cap Sources: includes (4-4b) 4K1B: KVG compressor east, (8-1) 8H1: Crude furnace, (10-2) 10H1: Asphalt mix heater, 20H2: Fractionator charge heater, ETF portable diesel generator, (4-4a) 4K1A: KVG compressor west, (51-8) Boiler #8, Hydrogen plant, (6-1) 6H1: Reformer charge and reheater furnace, (7-2) 7H1: HF alkylation regeneration furnace, (51-4) Boiler #4, (68-2) 68H2: North in-tank asphalt heater, (51-9) Boiler #9, (6-4a) 6K1 SVG compressor east, (7-1) 7H3: HF alkylation depropanizer reboiler, (9-1) 9H1: DHT reactor charge heater, (17-1) SRU - tailgas incinerator, 20H1: Reactor charge heater, $SO_2$ Emissions Cap Sources, (6-2) 6H3: Reformer reheat furnace, (45-1) 45H1: Asphalt mix and storage furnace, (19-1) DHT reactor charge heater, SRU/TGI (2), (4-1) 4H1: FCC feed heater, (6-3) 6H2: Prefractionator reboiler heater, (13-1) 13H1: Isomerization reactor feed furnace, (51-7) FCC 34" CO boiler bypass, Vacuum tower and vacuum furnace heater, Asphalt tank heaters, (12-1) 12H1: NHDS reactor charge furnace, (51-5) Boiler #5, Hot oil heater, (9-2) 9H2: DHT stripper reboiler, (11-1) 11H1: SRGP depentanizer reboiler, (51-6) CO boiler/FCC scrubber, (68-3) 68H3: South in-tank asphalt heater, (6-4b) 6K2: SVG compressor west, (51-10) Boiler #10

II.A.63 **$PM_{10}$ Emissions Cap Sources**
$PM_{10}$ Emissions Cap Sources: includes (8-1) 8H1: Crude furnace, (10-2) 10H1: Asphalt mix heater, 20H2: Fractionator charge heater, ETF portable diesel generator, (51-8) Boiler #8, Hydrogen plant, (6-1) 6H1: Reformer charge and reheater furnace, (7-2) 7H1: HF alkylation regeneration furnace, (51-4) Boiler #4, (68-2) 68H2: North in-tank asphalt heater, (51-9) Boiler #9, (7-1) 7H3: HF alkylation depropanizer reboiler, (9-1) 9H1: DHT reactor charge heater, (17-1) SRU - tailgas incinerator, 20H1: Reactor charge heater, (6-2) 6H3: Reformer reheat furnace, (45-1) 45H1: Asphalt mix and storage furnace, (19-1) DHT reactor charge heater, SRU/TGI (2), (4-1) 4H1: FCC feed heater, (6-3) 6H2: Prefractionator reboiler heater, (13-1) 13H1: Isomerization reactor feed furnace, Vacuum tower and vacuum furnace heater, Asphalt tank heaters, (12-1) 12H1: NHDS reactor charge furnace, (51-5) Boiler #5, Hot oil heater, (9-2) 9H2: DHT stripper reboiler, (11-1) 11H1: SRGP depentanizer reboiler, (51-6) CO boiler/FCC scrubber, (68-3) 68H3: South in-tank asphalt heater, (51-10) Boiler #10

## II.B Requirements and Limitations

II.B.1 **<u>Conditions on Permitted Source</u>**

II.B.1.a Stack testing to determine compliance shall be performed in accordance with the requirements of Section IX.H.1.a of the $PM_{10}$ SIP. The source shall be tested if directed by the Executive Secretary.

The (51-6) CO Boiler/FCC Scrubber shall be tested for $PM_{10}$ compliance at least once every five years. [R307-150]

II.B.1.b The emissions of $NO_x$ from heaters 8H1 and 12H1 shall not exceed 0.10 lb/mmBtu on a 3-hour average basis each. Compliance shall be determined by stack test to be performed every five (5) years.

The emissions of $NO_x$ from boilers #9 and #10 shall not exceed 0.020 lb/mmBtu on a 3-hour average basis each. Compliance shall be determined by stack test to be performed every five (5) years.

Except as specified below, emissions of $NO_x$ shall be determined through use of 40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

Emissions of $NO_x$ and $SO_2$ from the FCCU shall be determined through use of a CEM. The monitoring system shall comply with all applicable sections of R307-170-1, and 40 CFR 60, Appendix B, Specifications 2 ($NO_x$) and 3 ($O_2$). [R307-401, R307-170]

II.B.1.c The applicant shall provide a notification of any performance test date at least 30 days prior to the test. A pretest conference shall be held if directed by the Executive Secretary. It shall be held at least 30 days prior to the test between the owner/operator, the tester, and the Executive Secretary. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and of the Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA).

A sample location shall be chosen as outlined in 40 CFR 60 Appendix A, Method 1. The volumetric flow rate shall be determined by 40 CFR 60 Appendix A, Method 2.

To determine mass emission rates, the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation.

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three years. [R307-165]

II.B.1.d Visible emissions shall not exceed the following specifications:

All scrubbers: 15% opacity
All baghouses: 10% opacity
All combustion sources without controls: 10% opacity
FCC Unit/(51-6): 20% opacity
(8-1) 8H1 Crude Furnace: 20% opacity
Flares - 20% opacity
All fugitive emission points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. [R307-401]

II.B.1.e The amine plants shall reduce the $H_2S$ content of the refinery fuel gas to 0.10 grain/dscf (160 ppm) or less. The owner/operator has installed and maintains a continuous monitoring system for monitoring the $H_2S$ content of the refinery fuel gas and a continuous recorder to record the $H_2S$ in the refinery fuel gas. The monitoring system shall comply with all applicable sections of R307-170-1, and 40 CFR 60, Appendix B, Specification 7. [R307-401]

II.B.1.f Except as outlined in conditions II.B.1.g and II.B.1.h, the total hours of operation for testing and maintenance purposes for all emergency diesel-powered equipment shall not exceed 300 hours per 12-month period, without prior approval in accordance with R307-401. Compliance with the annual limitation shall be determined on a rolling 12-month total. By the last day of each month a new 12-month total shall be calculated using the previous 12 months. Records of the hours of operation shall be kept for all periods when the plant is in operation. Records of the hours of operation shall be made available to the Executive Secretary or the Executive Secretary's representative upon request, and shall include a period of two years ending with the date of the request. The total hours of operation may be determined by an engine hour totalizer installed on each engine, but a separate record of non-emergency hours shall be kept on a weekly basis. Emissions from this equipment shall not be included under the emissions cap. [R307-401]

II.B.1.g Except for use in emergency generators, fuel oil shall not be burned in any existing combustion device at the refinery except during periods of natural gas curtailment.

Emergency generators shall be used for electricity producing operation only during the periods when electric power from the public utilities is interrupted, or for regular maintenance of the generators. Records documenting generator usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage.

Torch oil may be burned in the FCCU regenerator to assist in starting, restarting, maintaining hot standby, or maintaining regenerator heat balance.

Small (<100 HP) portable fuel oil-powered equipment is exempt from the requirements of this AO and related emissions are not to be used for purposes of determining compliance. [R307-401]

II.B.1.h The ETF portable diesel generator shall not be operated more than 1,300 hours per rolling 12-month period without prior approval in accordance with R307-401. The total hours of operation shall be determined by an engine hour totalizer or by supervisor monitoring and maintaining of an operations log. [R307-401]

II.B.1.i The throughput of the catalytic cracking unit shall not exceed 3,250,000 barrels per rolling 12-month period. Compliance with the annual throughput limit shall be measured with a throughput flow meter. [R307-401]

II.B.1.j Compliance with the annual limitations shall be determined on a rolling 12-month total except where specifically exempted or otherwise provided for. By the last day of each month, a new 12-month total shall be calculated using the previous 12 months. Records shall be kept for a period of five years. [R307-401]

II.B.2 **Conditions on the SRU/Tail gas incinerators (3 units)**

II.B.2.a Copies of the SRU Operating Instruction/Standard shall be made available to the Executive Secretary upon request. [R307-401]

II.B.2.b Holly shall utilize monitors to measure volumetric flow rates from the Unit 17 SRU stack. The flow measurement shall be in accordance with the requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75, Appendix A. [R307-401]

II.B.2.c The three SRUs shall each achieve 95% recovery efficiency for all periods of operation except during periods of startup, shutdown or malfunction of the SRU. [R307-401]

II.B.2.d The Unit 17 SRU/Tail gas incinerator shall be equipped with a CEMS to measure $SO_2$ emissions. The 95% recovery efficiency shall be determined on a daily basis; however compliance shall be determined on a 30-day rolling average basis by measuring the flow rate and concentration of hydrogen sulfide ($H_2S$) in the feed streams going to the Unit 17 SRU and by measuring the $SO_2$ emissions with the CEMS at the SRU incinerator. The flow rate shall be determined continuously; the $H_2S$ concentration shall be determined quarterly for the first four quarters and at least semiannually thereafter. The flow rate and the $H_2S$ concentration values shall be used to determine the daily feed rate.

The 95% recovery efficiency for the new SRUs shall be determined on a daily basis; however compliance shall be determined as outlined in Section IX.H.1.i of the $PM_{10}$ SIP. [R307-401]

II.B.2.e All sulfur pit emissions shall be routed to an SRU incinerator. [R307-401]

II.B.2.f If sulfur input to the Unit 17 SRU exceeds 20 long tons per day, NSPS Subparts A and J shall apply. [40 CFR 60 Subpart J]

II.B.2.g The refinery may exercise an option to trade allowed annual SRU $SO_2$ emissions for cap sources' $SO_2$ emissions in the event the Unit 17 SRU is operating at better than 95% efficiency. This option shall not be made available until at least one year of data (12 efficiency determinations), as described below, has been collected and a trade-off request is submitted to and approved by the Executive Secretary. The (Unit 17 SRU) 24-hour minimum operating efficiency shall have been demonstrated to be no less than 95%. When the SRU efficiency, as determined below, is greater than 95%, adjustments to the annual $SO_2$ emission limit for cap sources [see Special Provisions II.A.61($SO_2$), II.A.62 ($NO_x$), and II.A.63 ($PM_{10}$) for the definitions of cap sources] may be made by the following procedure:

An adjusted annual cap emission limit is the annual cap sources' emission limit adjusted upward. This adjustment is derived from $SO_2$ emission decreases resulting from a better than 95% efficient SRU operation.

The adjusted annual cap emission limit shall only be used for compliance demonstration purposes. The combined annual total cap sources' and SRU $SO_2$ limit used for attainment and maintenance demonstration shall not be increased.

Daily compliance limits shall not be adjusted. [R307-401]

II.B.3 **Conditions on $SO_2$ emissions sources**

II.B.3.a The emission of $SO_2$ into the atmosphere [excluding the (51-6) CO Boiler/FCC Scrubber, emissions from flares and during SRU down times] shall not exceed 954 tons/year.

Emissions of $SO_2$ shall be limited as follows:

| Emission Points | Emissions (TPD) | Total Emissions (tons/yr) |
|---|---|---|
| (17-1) SRU Tail Gas Incinerator | 1.60 | 582 |
| SRU Tail Gas Incinerator #1 | 0.25 | 90 |
| SRU Tail Gas Incinerator #2 | 0.25 | 90 |
| Emission Cap sources | 0.53 | 192 |

Tons Per Day (TPD) = Daily 24-hour total. Daily means an interval of time between two consecutive midnights.

For all above listed emission points a CEM shall be used to determine compliance as oulined in II.B.3.d. [R307-401]

II.B.3.b Prior to the installation of the FCC Scrubber but not after December 31, 2012, the emissions of $SO_2$ into the atmosphere from the (51-6) CO Boiler shall not exceed the following: 3.147 TPD or 1148.83 tons/year

Upon installation of the FCC Scrubber but no latter than December 31, 2012, the emissions of $SO_2$ into the atmosphere from the (5106) CO Boiler/FCC Scrubber shall not exceed the following: 1.93 TPD or 706 tons/year.

Tons Per Day (TPD) = Daily 24-hour total. Daily means an interval of time between two consecutive midnights.

For emission point (51-6) stack testing shall be performed as outlined in condition II.B.1.a. [R307-401]

II.B.3.c The following sources shall not be regulated for $SO_2$ emissions, nor shall they be included in the emission limitation totals herein:

(66-1) Process Flare South
(66-2) Process Flare North
(68-1) Propane Pit Flare
Emergency Equipment

[R307-401]

II.B.3.d $SO_2$ emissions for the emissions cap sources shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel burned. $SO_2$ emission factors for the various fuels shall be as follows:

Natural gas - 0.60 lb $SO_2$/MMscf (Compressors Only)

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor which will measure the $H_2S$ content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily $H_2S$ content data from the continuous emissions monitor (CEM). The emission factor shall be calculated as follows:

(lb $SO_2$/MMscf gas) = (24 hr avg. ppmv $H_2S$)/10^6 * (64 lb $SO_2$/lb mole) * (10^6 scf/MMscf)/(379 scf / lb mole)

Fuel oil - The emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method 0-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

(lb of $SO_2$/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g $SO_2$/32 g S)

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted only during periods of natural gas curtailment. The sulfur content of the fuel oil shall be tested if directed by the Executive Secretary.

Fuel Consumption shall be measured as follows:

Natural gas consumption shall be determined by the meter totalizer on the natural gas supplied to the plant.

Plant gas consumption shall be determined through the use of flow meters.
Fuel oil consumption shall be measured each day by means of leveling gauges on all tanks that supply oil to combustion sources.

The equations used to determine emissions for the emission cap sources shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs)/(2,000 lb/ton)

Total daily $SO_2$ emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above $SO_2$ emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept which include the CEM readings for $H_2S$ (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt. %S, recorded for each day any fuel oil is burned), and the calculated emissions. [R307-401]

II.B.4 **Conditions on $NO_x$ emissions sources**

II.B.4.a Maximum $NO_x$ emissions to the atmosphere shall not exceed 2.09 tons per day. The emissions of $NO_x$ from all sources shall not exceed 669 tons/year. [R307-401]

II.B.4.b The following sources shall not be regulated for $NO_x$ emissions, nor shall they be included in the emission limitation totals herein:

(66-1) Process Flare South
(66-2) Process Flare North
(68-1) Propane Pit Flare
Emergency Equipment

[R307-401]

II.B.4.c $NO_x$ emissions for the Emissions Cap Sources shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted.

Boilers and Furnaces:

Natural gas/refinery fuel gas combusted using Low $NO_x$ burners:  81 lbs/MMscf
Natural gas/refinery fuel gas combusted using Ultra-Low $NO_x$ burners:  41 lbs/MMscf
Natural gas/refinery fuel gas combusted using all other burners:  140 lbs/MMscf
Natural gas/refinery fuel gas combusted using SCR: 41 lbs/MMscf
All fuel oil combustion:  120 lbs/Kgal

Where "Natural gas/refinery fuel gas" shall represent any combustion of natural gas, refinery fuel gas, or combination of the two in the associated burner.

Daily natural gas consumption shall be determined by the meter totalizer on the natural gas supplied to the plant.

Daily plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.  Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Compressors:

The $NO_x$ Emission Factor for natural gas (firm supply) combustion in the compressor drivers shall be 3400 lb/MMscf.

Daily natural gas (firm supply) consumption for the compressor drivers shall be quantified by meters, which shall be installed if necessary, that will differentiate the flow of natural gas to the compressors from the flow to the boilers and furnaces.

The emissions shall then be determined using the following equation:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Tota1 24-hour $NO_x$ emissions for sources included in the emissions cap shall be calculated by adding the results of the above $NO_x$ equations for plant gas, fuel oil, and natural gas combustion.  Results shall be tabulated for every day, and records shall be kept which include the meter readings (in the appropriate units), emission factors, and the calculated emissions. See Section IX.H.1.i(2) of the $PM_{10}$ SIP for details of compliance determination.  [R307-401]

II.B.5 **Conditions on $PM_{10}$ emissions sources**

II.B.5.a Prior to the installation of the FCC Scrubber, but no later than December 31, 2012, the emissions of $PM_{10}$ into the atmosphere from the (51-6) CO Boiler shall not exceed 0.36 TPD or 131.4 tons/year. $PM_{10}$ emissions from the emission capped sources shall not exceed 0.13 TPD or 47 tons/year.

Upon the installation of the FCC Scrubber, but no later than December 31, 2012, the emissions of $PM_{10}$ into the atmosphere from the (51-6) CO Boiler/FCC Scrubber shall not exceed 0.09 TPD or 32 tons/year. $PM_{10}$ emissions from the emission capped sources shall not exceed 0.13 TPD or 47 tons/year. [R307-401]

II.B.5.b The following sources shall not be regulated for $PM_{10}$ emissions, nor shall they be included in the emission limitation totals herein:

(4-4a) 4K1A KVG Compressor West
(4-4b) 4K1B KVG Compressor East
(6-4a) 6K1 SVG Compressor East
(6-4b) 6K2 SVG Compressor West
(66-1) Process Flare South
(66-2) Process Flare North
(68-1) Propane Pit Flare
Emergency Equipment

[R307-401]

II.B.5.c $PM_{10}$ emissions for the Emissions Cap Sources shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted in each unit. $PM_{10}$ Emission Factors for the combustion sources will be as follows:

Natural gas: 5 lb $PM_{10}$/MMscf
Plant gas: 5 lb $PM_{10}$/MMscf

The $PM_{10}$ emission factor for fuel oil combustion shall be determined based on the $H_2S$ content of the fuel oil as follows:

$PM_{10}$ (lb/kgal) = (10 * wt.%S) + 3

Daily natural gas consumption for each cap source shall be determined by the meter totalizer on the natural gas supplied to the plant.

Daily plant gas consumption for each cap source shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks that supply fuel oil to combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Total 24-hour $PM_{10}$ emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above $PM_{10}$ emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt. %S), and the calculated emissions. For the details of compliance demonstration, refer to Section IX.H.1.i(2) of the $PM_{10}$ SIP. [R307-401]

## Section III: APPLICABLE FEDERAL REQUIREMENTS

In addition to the requirements of this AO, all applicable provisions of the following federal programs have been found to apply to this installation. This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including UAC R307.

NSPS (Part 60), J: Petroleum Refineries
NSPS (Part 60), Dc: Small Indus Com InstitnSteamGenratr
MACT (Part 63), CC: Petroleum Refineries
NESHAP (Part 61), FF: Benzene Waste Operations
NSPS (Part 60), GGG: VOC Equip Leaks Petro Refineries
MACT (Part 63), ZZZZ: Recipro. Int. Comb Engine (RICE)
NSPS (Part 60), QQQ: VOC Emis Petro Ref Wastewtr Sys
NSPS (Part 60), A: General Provisions
MACT (Part 63), UUU: Petro Refineries Cat Crkg,Ref,SPU
MACT (Part 63), R: Gasoline Distribution
NSPS (Part 60), Kb: VolatLiq/PetroStorageVessel 7/23/84

## PERMIT HISTORY

This AO is based on the following documents:

| | |
|---|---|
| Is Derived From | Additional Information: CO Source Wide PTEs dated November 17, 2009 |
| Supersedes | DAQE-AN0101230027-09 dated November 3, 2009 |
| Is Derived From | Updated NOI dated October 19, 2009 |
| Is Derived From | NOI dated September 28, 2009 |

# ACRONYMS

The following lists commonly used acronyms and associated translations as they apply to this document:

| | |
|---|---|
| 40 CFR | Title 40 of the Code of Federal Regulations |
| AO | Approval Order |
| BACT | Best Available Control Technology |
| CAA | Clean Air Act |
| CAAA | Clean Air Act Amendments |
| CDS | Classification Data System (used by EPA to classify sources by size/type) |
| CEM | Continuous emissions monitor |
| CEMS | Continuous emissions monitoring system |
| CFR | Code of Federal Regulations |
| CO | Carbon monoxide |
| COM | Continuous opacity monitor |
| DAQ | Division of Air Quality (typically interchangeable with UDAQ) |
| DAQE | This is a document tracking code for internal UDAQ use |
| EPA | Environmental Protection Agency |
| HAP or HAPs | Hazardous air pollutant(s) |
| ITA | Intent to Approve |
| LB/HR | Pounds per hour |
| MACT | Maximum Achievable Control Technology |
| MMBTU | Million British Thermal Units |
| NAA | Nonattainment Area |
| NAAQS | National Ambient Air Quality Standards |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NOI | Notice of Intent |
| $NO_x$ | Oxides of nitrogen |
| NSPS | New Source Performance Standard |
| NSR | New Source Review |
| $PM_{10}$ | Particulate matter less than 10 microns in size |
| $PM_{2.5}$ | Particulate matter less than 2.5 microns in size |
| PSD | Prevention of Significant Deterioration |
| PTE | Potential to Emit |
| R307 | Rules Series 307 |
| R307-401 | Rules Series 307 - Section 401 |
| $SO_2$ | Sulfur dioxide |
| Title IV | Title IV of the Clean Air Act |
| Title V | Title V of the Clean Air Act |
| TPY | Tons per year |
| UAC | Utah Administrative Code |
| UDAQ | Utah Division of Air Quality (typically interchangeable with DAQ) |
| VOC | Volatile organic compounds |